COMMITTEE HEARING

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	
Preparation of the 2005	)	Docket No.
Integrated Energy Policy	)	04-IEP-1D
Report	)	
	)	
Committee Hearing on the	)	
California and Western	)	
Electricity Supply Outlook	)	
Report	)	
	)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, JULY 26, 2005

9:05 A.M.

Reported by:
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Contract No. 150-04-002

COMMISSIONERS PRESENT

John L. Geesman, Presiding Member

ADVISORS

Melissa Jones, Advisor

Michael Smith, Advisor

STAFF PRESENT

Al Alvarado

Jim Woodward

Richard Jensen

Mike Jaske

ALSO PRESENT

Stan Holland, WECC

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I N D E X

P R O C E E D I N G S

9:05 a.m.

PRESIDING MEMBER GEESMAN: This is the 48th day of workshops of the California Energy Commission Integrated Energy Policy Report Committee. I am John Geesman, the Commission's Presiding Member of that Committee.

Unfortunately, Commissioner Boyd, the Associate Member of the Committee, will not be able to join us today because of a schedule conflict that requires him to be in Southern California.

To my left is Mike Smith, his staff advisor. To my right, Melissa Jones, my staff advisor.

The purpose of today's workshop is review of a staff report and hearing from some of our regional colleagues on the California and Western Electricity Supply Outlook Report.

Al.

MR. ALVARADO: Good morning. My name is Al Alvarado, I am the Project Manager of the Electricity Supply Assessments that we are conducting for this 2005 Energy Report. Today we are going to provide an overview of the staff report on Statewide and Western Electricity Supply Outlook.

This is a second report accompanying another report we had a workshop on late June on the Investor-Owned Utilities Supply Outlook Report.

I would like to introduce Jim Woodward who is the principle author of this report and providing an overview and be fielding any of your questions today.

MR. WOODWARD: Thank you, Al. Good morning to those here and those listening on the web.

I am Jim Woodward, and I am proud to work for the California Energy Commission in the Electricity Analysis Office. The next 30 minutes or so I'll be presenting highlights and sample findings from the California and Western Electricity Supply Outlook Report.

This staff report had many contributing authors in the Electricity Analysis Office. Most of them are here today, and I am hoping they can help answer the more difficult or leading questions at the end of this little talk.

I would also like to acknowledge the

many utility and ESP resource planners who provided a wealth of data, information, and insights about their own procurement plans and contractual relationships.

They candidly discussed market uncertainties involving gas prices, transmission, renewables, resource adequacy rules, and more. The uncertainties faced by LSE portfolio managers and resource planners are detailed in Appendix B along with some general approaches to prudent risk management strategies that they employ.

This 89-page report with 49 pages of appendices represents our best professional judgement. Our best efforts to assess and describe the information we reviewed, summarized now for public review and consideration.

We have taken unusual pains not to disclose data that is proprietary or business sensitive. We are obliged to protect confidential data included that which has been granted and that covered by pending appeals.

Out of respect for the data we cannot present or discuss today, I would like to ask for a moment of silence.

(Laughter.)

MR. WOODWARD: Thank you. This report provides a detailed overview of California's electricity supply trends through the year 2016. The Energy Commission is required to make extensive regular assessments of all aspects of statewide energy demand and supply according to Public Resources Code Section 25301.

The Energy Commission staff has been asked to identify load trends and understand resource development trends that taken together affect the strength and reliability of the state's electric system.

These assessments are one basis for the Energy Commission's biennial report, which in turn becomes the foundation for policy recommendations to the Governor, the Legislature, and other agencies.

This report summarizes four separate staff assessments into a single document. First, a five-year outlook of electricity supply and demand to determine whether California's electricity system can maintain its required seven percent operating reserve margin.

Second, a review of supply demand outlooks through 2016 prepared by numerous planning and power marketing organizations in the western interconnection.

This review was aimed to assess the extent to which electricity surpluses outside California will continue to be available for import.

Third, the report summarizes the electricity resource plans submitted by 13 publicly-owned utilities and 5 energy service providers in California that had peak loads of at least 200 megawatts in 2003 or 2004. This statewide summary for all medium and large electric retailers also includes data submitted by the state's 3 large investor-owned utilities.

Fourth, the report includes a retail price forecast for California LSEs covering 2006 to 2016.

This report, in Chapter 2, provides a short background on California's electricity generation and transmission systems, including recent additions and retirements.

In Chapter 4, this report strives to present a transparent understanding of supply-adequacy as it relates to procurement capabilities of publicly owned utilities and energy service providers.

Also in Chapter 4, an overview of customer choice and direct access are presented. This primer is helpful in providing context for an industry that has undergone monumental change after nearly a century of vertically-integrated stability.

Appendix A provides additional details about California power plant additions and retirements expected between 2006 and 2008.

Appendix B presents summaries of the Resource Plans submitted by 13 publicly owned utilities and 5 Energy Service providers. The Investor-Owned Utility Resource Plan Summary Report provides lots of detail on IOU Resource plans, which were publicly presented here at an Energy Report hearing on June 29.

Appendices C, D, and E include tables that examine California retail price outlook in more detail.

Electricity use varies widely over the time of day and time of year. For example, the annual pattern of daily peak demand shows great spikes during hot summer months. Peak loads on weekends are much less than on weekdays all year long. This variable load requires a generation system that is extremely flexible.

Our concern for reliability, having adequate resources to meed demand, is often focused on just a few hours in the month or year. This figure shows actual 2004 hourly demand as reported by CA ISO, sorted from high to low levels; with the peak hour, hour 1, on the left, equal to 45,597 MW.

Peak electricity demand increases dramatically in the summer due to air conditioning loads. Again, this generation system must be capable of adding or dropping generation from some facilities to accommodate the wide daily swings in demand, the high summer peaks, weather variability, and economic growth cycles.

California ability to maintain minimum required operating reserve margins over the next five years will be largely determined by its ability to reduce demand and secure the necessary resources to meet increased load.

Project capacity additions will maintain adequate reserve margins sufficient to meet load growth due to population increase and economic expansion, if existing capacity is maintained.

The Energy Action Plan Loading Order has been established as the preferred method of securing additional resources, so it is crucial to understand how LSEs plan to implement the loading order to meet future customer loads.

Nearly two-third of the plants identified as high risk for retirement are located in Southern California. The Aging Power Plant report identified several power plants with a high risk of retirement if they do not secure contracts that provide financial incentives for continued operation.

This figure illustrates the impact of high-risk retirements on SP26, the region that currently has the smallest percentage of reserve capacity.

If high-risk retirements are not considered, projected operating reserves in SP26 exceed 7 percent until summer 2009 under hot temperature, and high forced and planned outage conditions. This includes planned additions, the green bars on the chart, that keep up with forecast load, this black line on the chart. Forecast load growth steadily increases from 2006 to 2010. this scenario above the line, assumes that plants that are at high risk of retirement will be maintained, or that their capacity will be replaced with demand reductions or additional resources.

But if all the plants under the High-Risk Retirement Scenario do indeed retire, projected operating reserves could fall below 7 percent during average conditions in 2006, and in the event of adverse temperature conditions a CA ISO Stage 3 declaration and rotating outages could occur.

Beyond 2006, if aging power plants retire and are not replaced, California's electricity system will not be able to maintain the required the 7 percent operating reserve margin during high-demand periods of very hot weather. Beyond 2005, if aging power plants retire and are not replaced, most of Southern California will be unable to maintain this margin even under normal temperature conditions.

In the Supply Outlook Report, Table 2-3 provides a summary of the amount of capacity considered under the high-risk retirement scenario and the first year in which it is at risk to retire. In determining projected operating reserves under both scenarios, several high-probability generation additions were included through 2008. A summary of these additions in included in Table 2-4. Complete listings for both tables are included in Appendix A.

Looking beyond our borders, California will continue to rely heavily upon imported electricity from the Southwest and Northwest. Surplus electricity from the Southwest has been California's main source of imported power, but that region's continued fast growth will likely absorb future surpluses.

The Northwest will continue to have a large surplus of electricity capacity available for export to California and the Southwest in summer months. But a portion of this capacity will be stranded in the Northwest due to transmission constraints.

Two sub-regions within the Western Interconnection are particularly important to California: the Pacific Northwest (including Western Canada), and the Desert Southwest. Chapter 3 of the Supply Outlook report supplies a summary of the 2005 Power Supply Assessment done by the Western Electricity Coordinating Council.

We will hear more about that assessment in a few minutes from our next speaker, Stan Holland.

Under the two summer scenarios, both Western Canada and Northwest sub-regions have resource surpluses throughout the forecast period, which for WECC was through 2014.

for its winter peaking load, the Northwest can meet forecast demand under both current and extreme weather conditions, but may not meet the 15 percent planning reserve margin beginning in 2013.

In the Southwest, capacity reserve margins are diminishing due to a recent slowdown in generation additions, and record levels of load growth (largely driven by population growth around Las Vegas and Phoenix).

The Desert Southwest might experience a supply deficiency beginning in summer 2008 due to extreme hot temperatures-like we had a week ago- along with continued load growth around Las Vegas and Phoenix.

In this table, we show recent and proposed generation additions for the four WECC sub-regions.

Capacity additions are characterized as

"operational" if they had on-line dates from spring of 2000 through May 2005. More than 40,000 megawatts of new generating capacity became operational during that period. Another 9,354 MW of new capacity additions have either begun site preparations or are further along in their construction. Once the plants in this category are completed and on-line, the WECC region will have more than 49,000 MW of new capacity since spring 2000, most of which was installed in the California-Mexico and Southwest sub-regions.

Proposed capacity additions include power plants in one of four stages of development. The first would be plants that have received approval and necessary permits to build and operate, but have not yet started construction. Over 12,000 MW are in this category.

The next column of Proposed additions are plants in the regulatory approval and permitting process. Another 10,000 MW is in this category. A third category is for plants that have recently begun the approval process, which would add another 10,800 MW if they all came to fruition.

Fourth and least certain are additions

that have been announced in a press release that provides project details such as developer, location, and capacity which altogether would be another 9,700 MW.

The Pacific Northwest currently has large reserve margins, particularly in the off-peak summer months. A review of resource plans filed at regulatory agencies throughout the Northwest reveals that while the region as a whole is fully resourced, individual LSEs will need to acquire some resources during the next decade to meet their demands, especially during winter peak seasons. This is primarily due to load growth and contract expirations during the forecast period.

Many Northwest LSEs are contemplating developing thermal generation and renewable projects in order to meet their future demand. This includes company-owned generation in the resource plans for Idaho Power, Sierra Pacific Power in Nevada, and the Energy Northwest Consortium in Washington.

This is Figure 3-3 in the Supply Outlook Report, illustrating proposed incremental new capacity additions in the region. Projects included in this figure are in various stages of development, but all have applied for the required permits.

Natural gas-fired power plants, shown with the green and white diagonal lines, and wind generation, shown in purple, make up the largest source of recent, short-term, and mid-term additions, which coal-fired generation, shown as green background with white dashes, could represent the majority of long-term additions after 2008. A detailed list of proposed projects is posted on the Energy Commission website.

Interestingly, most Northwest LSEs are continuing with plans to implement energy efficiency and demand-reduction to programs. These programs will help Northwest LSEs meet their winter peak load obligations, and some programs will reduce energy consumption all year long. When those programs help reduce summer loads, it will increase the Northwest region's ability to export excess energy to California during our peak demand months.

Major utilities in the Southwest plant to meet load growth through a combination of generation additions and power contracts. For example, Nevada Power Company and Public Service

Company of New Mexico recently purchased partially-built power plants named Charles Lenzie and Luna, to complete construction and serve their loads.

Nevada Power Company recently announced it would purchase a 75 percent share of the Silverhawk Facility with 570 MW near Las Vegas. In Arizona, APS is relying on contracted power to meet soaring peak demand. APA recently issued a request for proposals to provide 1,000 MW to meet peak and energy needs for a minimum of five years beginning in 2007. Tucson Eclectic Power is developing the Springerville Unit 3 Power Plant which is expected to be online in 2006 with 400 MW.

This figure again shows incremental annual capacity additions, dominated by gas-fired plants with some wind in the first three years, with more coal-fired plants starting in 2008.

This figure should have been labeled the Southwest and Rocky Mountain sub-regions, and I regret the error. It is correctly labeled in the Supply Outlook Report as Figure 3-8.

In Colorado, the single largest LSE in that state, Xcel Energy, is planning to build a

750 MW addition to the Comanche coal-fired facility to meet 20 percent of its forecasted resource needs. In general, a review of LSE resource plans suggests that more coal than natural gas-fired generation will be built in the future. because of concern about natural gas supplies and prices.

Earlier this year, the Energy Commission undertook the first detailed examination since 1996 of California's electrify supply resources. A total of 21 medium and large electricity retailers were asked to provide forecasts of load obligations and the generating or contractual resources used to serve that load.

Chapter 5 provides the Energy Commission staff's review of electricity resource plans filed by these LSEs. This represents about 97 percent of the retail load in California.

In 2006, the 21 reporting LSEs collectively expect their non-coincident peak demand to total approximately 55,800 MW. By 2016, this peak is expected to rise 7.7 percent to 60,091 MW.

A total of 35 small LSEs in California were exempt from filing resource plans because their peak retail loads in 2003 and 2004 were less than 200 MW. Altogether, these 35 exempt LSEs had non-coincident peak retial loads in 2004 totaling about 1,450 MW.

This figure provides a $30,000-foot reconnaissance-level snapshot of expected peak loads in California's retail markets through 2016. This is a multi-faceted aggregation of many different assumptions, forecasts, and estimates, using the annual demand, that is, the net peak customer demand (hour 1 on the load duration curve) that each LSE expects to serve during the next 11 years.

The top line shows peak load forecasts for the three large IOUs and Imperial Irrigation District. Their resource plans were granted confidentiality, at least in part, so these four LSEs have been grouped together to avoid disclosing business-sensitive data.

The net peak demand for each LSE includes a 15 percent planning reserve margin except for two Muni's who did not show this reserve margin in their filings, and except for LADWP which showed a planning reserve margin of nearly 20 percent. Roseville did not forecast capacity or energy numbers for 2015 or 2016, which explains the slight dip for POUs in those years.

This figure shows some remarkable aggregate stability in the collective assumptions about loads and market shares that each class of LSE could be called upon to serve. For example, in 2006, ESPs expect to serve 4.1 percent of the retail market, based on peak load. In 2016, these five ESPs as a group estimate their most likely market share, together, will still amount to 4.1 percent of total peak retail demand.

For these same 21 electric retailers, annual energy consumption is expected to increase from about 260,200 GWh in 2006 to 282,000 GWh in 2016, an 8 percent increase. Like the capacity numbers, the energy numbers include transmission losses, distribution losses, UFE, and station loads, so they are somewhat higher than expected retail sales. These numbers do not include firm sales obligations or expected spot market sales; nor do the energy numbers include a 15 percent planning reserve margin.

LSE forecasts of steady annual customer energy demand growth are show here, Figure 5-7 in the Supply Outlook Report. The three IOUs and IID together will provide 72.2 percent of this energy supply in 2006, and 71.1 percent in 2016.

The other 12 POUs will collectively supply and deliver 22 percent of this energy total in 2006, and 23 percent in 2016. The collective ESP share of these needed energy supplies is 5.9 percent in 2006, and about 5.8 percent in 2016.

What may be most remarkable about these numbers is the shared expectation among portfolio mangers of gradual, modest peak load growth and continuation of current market shares or energy delivery among classes of LSE.

Again, as a qualification, no one is ensuring that all forecast loads will be served by any particular LSE. What the IOUs assume will depart to direct access, or municipal service, or community choice aggregators was not necessarily matched by load growth assumptions as reported by those LSEs. Each LSE was asked to submit a full set of electricity supply forms incorporating their own preferences, assessments, strategies, and judgments. This included a request to the IOUs to use their own assumptions about departing load, energy efficiency, and renewable energy procurement. This is the data that was aggregated to provide this common understanding of statewide trends.

By 2016, about 25,000 MW of generic new supply resources will be needed to serve total peak requirements, including retail loads, a 15 percent planning reserve margin, and firm sales requirements. This includes power to replace expiring supply contracts and capacity to replace retiring plants.

The three IOUs will have the most need for generic resource additions, as show here, Figure 5-4 in the Supply Outlook Report.

These numbers are for dependable capacity all types, and they are cumulative over time. CPUC procurement proceedings have already authorized IOUs to fill much of this generic capacity need for the early years in the forecast period.

A couple of Muni's listed a LM 6000 plant or two on their long-term horizon, listed this as planned resources, which some might call a "generic resource addition" but we did not unilaterally amend or correct the resource plan filing data for any aggregation.

This figure, number 5-5 in the Supply

Outlook Report, shows the aggregate LSE estimates, collectively and cumulatively, of renewable and non-renewable generic resources reported in the 21 resource plans.

These are dependable capacity estimates, which may be significantly less than installed or nameplate ratings for new renewables. For example, LADWP has plans to bring the Pine Tree Wind project online in 2006. It has a nameplate rating of 120 MW, but the dependable capacity rating, for now, is 0 MW.

This figure, number 5-10 in the Supply Outlook Report, shows one primary procurement source of renewable energy that is not owned by utilities; bilateral contracts. These do not include renewable energy that some utilities expect to purchase on a short-term or spot market basis, or include renewable energy credits that might be purchased.

Annual data for the first three years in the forecast period are not included to avoid disclosing confidential data. For the IOUs, renewable contract supplies are based on their preferred case (PG&E) or their Alternative Cases (SCE and SDG&E respectively).

These cases assume an obligation that 20 percent of their retail energy sales will be supplied by eligible renewable energy resources by 2017. For Edison, this target will be achieved before 2009, which is reflected in a nearly constant forecast level to maintain this percentage through 2016, the end of the forecast period on the chart.

And now for a few highlights from the fourth and last assessment in the Supply Outlook Report. In this outlook, staff provides estimates of typical retail electricity rates, given projected energy prices, utility plans and programs, and regulatory decisions. The projection uses a set of assumptions that staff believes are probable and realistic. Staff uses the best available information including public knowledge and confidential data from the LSEs.

Retail customers of the state's investor-owned utilities can expect electricity rates to remain nearly constant from 2006 through 2016, and their rates will remain substantially higher than those in other western states.

For IOU customers, retail rates will continue to be higher than those paid by customers of the state's publicly owned utilities.

The generation portion of the retail electricity price amounts to at least 50 percent for most retail customers. For larger IOU customers, generation cost is higher than 50 percent of total costs. This trend will continue through the end of the outlook period.

The generation cost component for ESPs is expected to remain flat in the range of 5.4 to 5.9 cents per kilowatt-hour.

Charges for transmission, distribution, various surcharges, and all other non-generation charges add at least 5.3 cents per kilowatt-hour, and as much as 8.5 cents. All coinage is nominal. Details are presented in Table 6-3 of the report, and in Appendix E.

If current price trends continue, the differences in rates between California's investor-owned and publicly owned utilities will diminish over time.

The IOUs and most of the municipal utilities project stable electricity prices through the outlook period.

I would like to conclude by briefly presenting three figures drawn from Table 6-2 in the Supply Outlook Report. These 3 figures show the weighted average electricity prices for residential, commercial, and industrial customer of IOU and municipal utilities through 2016. For residential customers, the gap between IOU and POU customers clearly narrows over time, with a noticeable decline in IOU rates through 2008 at the beginning of the forecast period, and a slight rise in POU rates over the whole forecast period.

Rates for IOU customers include the cost of generation, transmission, distribution, public purpose programs, competition transition charge(CTC), nuclear decommissioning, Department of Water Resources (DWR) contract costs and bond financing, and other miscellaneous charges.

Although not generally listed in the bills, rates for municipal utility customers include similar costs, except that municipal utilities do not have DWR contracts, DWR bond financing, or competition transition charge costs.

Commercial customers can expect to see stable retail rates around 14 cents per kilowatt-hour among the IOU commercial customers. Their municipal counterparts can expect to pay, on average, about 4 cents per kilowatt-hour less.

For industrial customers, the difference between IOU and POU retail rates is up to 3.0 cents per kilowatt-hour in the early years. This gap narrows to 2.0 cents in 2014. consolidated retail prices for IOU and municipal utilities are listed in Appendix D.

All interested parties are encouraged to contribute comments in writing, and the Committee requests comments be submitted by August 5, 2005. Public comments and corrections to this staff report are welcomed, but we do not plan to publish another final version. This is it, we hope. If you are submitting comments to our Docket Office, please be sure to identify as pertaining to Docket 04-IEP-1D.

California's electricity system is physically interconnected with many local entities and embedded within a very large western interconnection. This report presents a detailed overview of electricity supply trends in California and the Western Electricity Coordinating Council region through the year 2016.

In the big picture, the goal of this and other Energy commission reports is to help in managing the growth of California's electricity supplies in a way that balances the interests of consumers, energy providers, the environment, and others with a stake in these outcomes.

Thank you.

PRESIDING MEMBER GEESMAN: Any questions from the audience for Jim? Steven.

MR. KELLY: Thanks, Jim, that was a very interesting presentation and transparent by the way.

PRESIDING MEMBER GEESMAN: You need to introduce yourself, Steve.

MR. KELLY: Steven Kelly with IEP. I have a couple of questions. On the graphs that show proposed generation in the Southwest, there was a pretty large chunk for coal. It looks about 50 percent, is that IGCC or is that just straight traditional coal that is expected to come on line for that?

MR. WOODWARD: For that question, I would like introduce Richard Jensen from our office.

MR. JENSEN: Commissioner, advisors, guests, Richard Jensen, Electricity Analysis Office. Forgive me if I am a little nervous, I haven't been in front of a live microphone in a while, since my brother's wedding several years ago, and hopefully I will fair better today.

IGCC I know of one project, the Mustang Project in New Mexico that actually has received some federal funding, a grant, looking into the development of that project, but the majority of the Southwest coal development would be pulverized coal.

MR. KELLY: Jim or to staff I guess, on the graph that shows key findings from the California Load Serving Entity Resource Plan filings, you show in 2006 non-coincident peak demand at 55,800 MWs increase to 60,091 MWs by 2016 over the course of ten years, which is about if my math is correct, about a 4,000 MW increase over that period of time over ten years.

As I recall during the late to mid 90's, we were increasing load 1,500 MWs I think even in PG&E's service territory during that kind of boom, economic boom period of that period.

This strikes me as a relatively low number for a period as long as ten years in terms of growth. I as wondering what's driving that? Is it that we are going to have demand reduction, or is it just the economic growth is going to be moderate during this ten-year period? Does anybody --

MR. WOODWARD: The demand drivers for many of the filings are detailed in Appendix B4 for some of the utilities in Southern California municipal utilities. They are seeing a built out service territory and only seeing very modest one to two percent annual demand growth.

MR. KELLY: Okay, I apologize, I haven't had the time to pour over the appendices. What is leading to what I view as relatively moderate low public growth over ten years is just a fairly consistent expectation amongst the load serving entities that demand is going to be relatively flat during this period. Is that what is going on here?

MR. WOODWARD: Yes.

PRESIDING MEMBER GEESMAN: I would emphasize, Steven, that this is a compilation of the filings that were received. I don't believe the staff is claiming authorship of the projection. I think Jim may have misspoke when he said one to two percent a year. I think arithmetic would suggest growth below one percent a year. I think in most financial analyses, you would probably go back over your recorded historic data and see if there is any ten-year sequence during that recorded period that would match the project for growth going forward.

I am not certain, at least in the 30 years that I know about, you could find any similar ten-year period of relatively no growth.

MR. KELLY: My math showed that over the ten-year period, there is about an eight percent growth rate, and I think on the energy side, too, the chart when I did the quick math in my head, it comes out to be about an eight percent growth rate over ten years, which struck me as relatively or historically low.

PRESIDING MEMBER GEESMAN: Which may provide some insight into the quality of submittals that we actually received.

MR. KELLY: That's right. I haven't poured through the report.

MR. JASKE: Mike Jaske, Energy Commission staff. Another dimension is simply the nature of the submittal process. As you indicated yourself earlier, Commissioner Geesman, this is a compilation, and there can be mismatches between the expectations of the IOUs about direct access and the ESPs about direct access that our process hasn't found a way in which to accommodate that mismatch. This is just a jamming together the sort of long staple approach as we used to talk about in WCSS of everyone's individual view. Only when you get something like the staff forecast where there is an attempt to be consistent and throughout and have the same methodology would you have something that is more like a reasonable view of the future.

MR. KELLY: I understand that, and I understand the problems that we have on this.

That gets me to kind of my next comment, and this deals with the slide that talks abut market share findings. I don't have these numbers, but it showed up on page 10 of the handout.

The first bullet said that the IOUs are expected to lose one percent of customer loads to publicly-owned utilities by 2016. The second bullet says the ESPs which I am not sure if those include the POUs or not expect to maintain a 6 percent market share through 2016.

If the IOUs are expecting to lose one percent of customer loads to some entity, and the

ESPs are going to maintain their market share. Are we losing load someplace?

PRESIDING MEMBER GEESMAN: Again, as Mike pointed out, this is a compilation. There is no required consistency between assumptions.

MR. KELLY: Okay.

PRESIDING MEMBER GEESMAN: It is an interesting insight into the self-recording process.

MR. KELLY: Correct. I don't know when the staff is going to or if they are going to put their visors on and give us the staff's outlook on this stuff which would be helpful I think at this point, but it seems to me that we might be losing some share there. I think the energy service providers are reporting a market share number which is going to fluctuate as the gross amount of demand moves over time, and the IOUs may be reporting just -- I am not sure if the 1 percent is a reduction off where they stand today, or is a 1 percent reduction off of the growth expectations that are going to occur over the ten-year period. Does anybody have an answer to know that?

MR. WOODWARD: The 1 percent reduction in market share adding up -- first we start with a

21 filings adding up to 100 percent of what they forecast in 2006 for the net peak demand for their retail customers.

That relative share declines by roughly 1.1 percent for the three IOUs from 2006 to 2016.

MR. KELLY: That 1 percent is a market share?

MR. WOODWARD: And is picked up by -- yes.

MR. KELLY: Okay, and where is it going then?

MR. WOODWARD: To the publicly-owned utilities.

MR. KELLY: Would that rightfully be another bullet here then because they are not included in the ESP bullet?

MR. JASKE: There is an element that is completely missing from our process, so it is not only difference of opinion among the fixed set of load serving entities, there is a class of load serving entity which has not contributed anything into this process, which is community choice aggregation. To the extent that the IOUs project loss of load to community choice aggregation, there are no community choice aggregators that are regulations required to submit anything, and so there is an actual amount of existing load which is sort of falling off the table from the perspective of the plans that all the existing load serving entities have turned in.

That is documented to a very limited degree in the staff paper of June 29 that was the aggregation of the IOU and all the LSEs into the planning area. You can kind of detect there's adjustments to load, but because of the confidentiality problems, they can't all be spelled out precisely how that works out.

MR. KELLY: Under the second bullet there, Energy Service Providers, that includes what I will call the Muni's and the ESPs that are registered at the PUC?

MR. WOODWARD: We did have that (indiscernible) a couple of times -- I remember one junior staff were assigned a complete resource plan and got the lines two and three on the forms and said how do I fill that out as an ESP. I said you are not an ESP, you are a Muni. I said, yeah, it is in our mission statement, we provide energy.

Well, ESPs as we've defined it here, five companies are energy service providers, not publicly-owned utilities.

MR. KELLY: This graph, just so I am understanding what it is, this graph actually is missing the CCA assumptions and it is missing the muni stuff.

MR. WOODWARD: No, municipal utilities gave us the forecast of their load growth, but they were not required to forecast an offset and match up load reductions that the IOUs may have assumed. They are independent assumptions. In fact, the resource plan filings are an aggregation of hundreds and hundreds of decisions and assessments, calculations, estimates, probabilities, and so on.

MR. KELLY: I appreciate the difficulty you guys at staff are trying to meld this, so, don't get me wrong here. Unless that load is leaving the state, it seems to me that there is a hole here, and I understand that it will take us probably years to figure this out, but it seems to me there is a statistical hole about a certain amount of load that is not being represented --

MR. JASKE: Again, it is not being represented within the resource plans that the existing load serving entities turned in. The load is represented in the staff forecast that was prepared independent of those LSE submittals, and there will be a supplemental staff filing on load forecasts in the early part of September that will address some of the uncertainties that we are talking about during the demand forecasting portion of these workshops.

MR. KELLY: To the extent that the Energy Commission is going to influence PUC procurement process, is it going to be the staff document that is transmitted over the PUC, or is it this document because --

PRESIDING MEMBER GEESMAN: Neither.

MR. KELLY: It will be the Commission approved document --

PRESIDING MEMBER GEESMAN: Approved by the Commission that will draw from the very rich evidentiary record that we have been able to develop in 48 days of workshops.

MR. KELLY: Got it, okay. I look forward to seeing how we make sure we've covered all of the holes here. Thank you.

PRESIDING MEMBER GEESMAN: Thank you, Steven. Other questions from the audience for Jim.

(No response.)

PRESIDING MEMBER GEESMAN: Great, let's go on then to our next speaker.

MS. JONES: I have one quick question, Jim. When you talked about the generic resource additions and for renewable, you mentioned that LADWP's project included zero dependable capacity. What was the range of dependable capacity for some of the other utilities? Was zero what all the utilities assumed, or was there some higher amount?

MR. WOODWARD: I don't recall in particular. For wind resources?

MS. JONES: Yes.

MR. WOODWARD: I don't recall that.

MS. JONES: Okay, thank you.

MR. WOODWARD: Any other comments, if not, it is my pleasure to introduce our next speaker, Mr. Stan Holland, Staff Engineer with the Western Electricity Coordinating Council.

MR. HOLLAND: Good morning, Commission, CEC staff, and guests. It is my pleasure to fill in for my boss today. The assessment that we did is actually still in draft form. It will be discussed at our board meeting this week, and most likely will be approved at that meeting.

The assessment had many people help with putting it together. We have Reliability Subcommittee that oversees the assessment, and we had a lot of help including from the CEC staff, Grace Anderson, Mike Jaske gave us good comments that we used.

The assessment like I said is a draft assessment still, and it is on our website if you want to see the whole thing.

In my presentation today, I am going to be using slides that were put together by John Leland, the chair of the Reliability Subcommittee. Then I will add some more details regarding California input data and then more details regarding California results from the assessment.

As many of you may know, the Supply Adequacy Model which is called SAM for short, was developed by the CEC staff and was given to WECC to use. Beginning the year 2001, we did our first assessment, we have been doing them every year since then. We used the deterministic mode of the model and also we will do problemistic as we point out later in this, we don't have the data to do more than a deterministic mode of the model.

The assessment evaluates physical ability of the interconnections to supply all load regardless of contractual obligations.

This means that we take all the loads, all the resources, and the transmission, and we let the model do its think. It computes a power supply margin, not a reserve margin.

These formulas here, they show the difference. If you were going to calculate your reserve margin, you would take the resources and the imports and you subtract the exports and the load.

If you have a target reserve margin, you put that in on the other side of the equation, and then you are going to get your surplus and deficiency.

You will see that the SAM calculation is similar to the second one where it calculates the surplus or deficiency with a reserve margin as an input.

The SAM model also calculates the imports and exports in order to try to meet the load requirement in each area.

This topology diagram shows the zones or bubbles that we divide the western interconnection up into for SAM to do its analysis.

The color coding, later you will see that post color codings are also how we aggregate the results for our report.

The data that we use for our assessment is supplied by WECC members. Each control area supplies us with their loads and resource data which includes 10 years of monthly load forecast data, existing generation capacities for both summer and winter, near-term generation additions and retirements, again, with the capacity information that we need, and this generation outage forecast, including schedule maintenance and forced outages for the current year.

We also ask our members to help us by giving us the zone to zone transmission transfer capability forecast. That means that if they know of upgrades or downgrades, that they will tell us which ones are highly likely, and we use those to feed the model.

The other thing that we started asking for recently is the sensitivity of their loads to temperature fluctuations. We use that in one of the scenarios that we will be talking about in a minute.

The data then is organized into zones, and each zone is assigned its load and resource and transfer capabilities, and then we apply the outages and the assumed reserve margin, and we export that into SAM, and SAM calculates the imports and exports at the zone level, and our assessment then is given a sub-region level to maintain confidentiality. I know that is a sore point, we are trying to get through that, and that might change eventually.

MR. SMITH: Mr. Holland?

MR. HOLLAND: Yes?

MR. SMITH: Quick question on the Southern California/Mexico area going back to your map. The data, do you have separate data -- is data broken out between Southern California and Mexico --

MR. HOLLAND: Yes, it is.

MR. SMITH: -- Northern Baja -- so, you have data for Northern Baja specifically?

MR. HOLLAND: Yes, for the area in Mexico that is in the WECC region, we get it from them.

MR. SMITH: Do you know the source of that data, who and what organization in Mexico generates that?

MR. HOLLAND: CFE.

MR. SMITH: CFE.

MR. HOLLAND: (Indiscernible).

MR. SMITH: Is that under some confidentiality protection, or is that available?

MR. HOLLAND: I don't think it is as much so as other places because in our reports that we published with the loads and resources, we have a California only, and then we have California/Mexico, so you could just do a subtraction and get the Mexico are portion of that.

Going from these zones to the sub-region level aggregation, this shows which zones are in a sub-region. Note that Northern California is made up of four zones, Southern California/Mexico is also made up of four zones.

This year we ran six scenarios, and there was a major change in how we came up with our reserve margin assumptions. Our Board asked us to reinstitute a criteria that was abandoned in 1999 called the Power Supply Design Criteria, so temporarily we are using that again to come up with an assumed reserve level.

You will see scenarios one and two are summer, and July is the peak the interconnection as a whole, so we use the July. Between Zone 1 and 2, the difference is that we apply a temperature deviation to try to get an extreme case.

Then Zone 3 and 4 are winter, which have no (indiscernible) for the South. Then 5 and 6 were thrown at the request of the Reliability Sub-Committee where we just take a straight 15 percent planning margin, and use that as the assumed reserve level.

Level 6 we then add the uncommitted generation. For those of you who haven't seen the report, committed generation is generation that is under active construction. Uncommitted generation that has been reported but is not underactive construction.

Some more about this power supply design criteria, there is three criteria, and it was recommended when this was in effect for each control area to meet one of these criteria. For this assessment, we assumed that the smaller criteria one or two must be met. Criteria 3 we have not analyzed at this point, it is more of a problemistic study that might be forth coming as we get more tools.

The largest risk we looked at was only generation. We didn't look at transmission, and there are bottle necks that could influence the results. Also, reserve sharing group benefits were not captured in this analysis.

An example of how this works is given here. You will see if you look under Zone 1 and go across, the Criteria 1 you can have 1a or 1b, and it is the greater of those. Then since they only have to meet the lesser of the criteria, then you take the greatest of 1a and 1b and the lesser of that versus Scenario 2. Most often, Criteria 1b and Criteria 2 are applicable to the zones in the study. Criteria 1a was never a factor.

Based on taking each zone and calculating the design criteria that would be applicable. You will see at the aggregate level what reserve margin was used in those scenarios. So, for Southern California/Mexico, it is around 11 percent. For WECC over all, it is around 11 percent.

Those were used for Scenario's 1 through 4, except the winter was used for the winter cases. Then the Scenario's 5 and 6, the 15 percent planning margin was assumed. Here are the summer results, this shows the year's first deficit, and the deficit zone ratio which is the ratio of the number of zones in the sub-region that are deficit compared to the total number of zones in the sub-region.

A deficit condition means that the sum of the power supply margins or the zones in the sub-region was negative. John Leland when he took our assessment and made these slides, he put colors into the results which makes it very easy to see how the results are good or bad.

The red is bad, the blue is good, the yellow is good, zero (indiscernible) margin means that the reserve requirement was meant. It just also means that there are likely transfers involved, and the model, both import more than is necessary to meet the requirement, so zero would be the answer in that case.

If we look at the example here of Southern California and Mexico sub-region, you will see that it goes deficit in the year 2009. The ratio we show here -- so you can look under Scenario 1, the bottom row there, 2009, Southern

California/Mexico goes deficit, but only one out of the four zones is really deficit. The others are actually still importing and able to meet their load requirements.

Throughout the assessment, we have several disclaimers, one of which is although we know the load requirements as forecast by the control areas out for ten years, it is not known what kind of resource additions or retirements will occur during those ten years.

We may know for two or three years. After that, nobody knows. At that point, the studies all shift from a determination of supply margin to a determination of future needs. Again, if you look on the table here under Southern California, if we take the results of this report in the year 2010, we would need 2,300 MWs of more generation.

This slide compares Scenario 1 and Scenario 2 where we increased the load requirement to account for a five degree increase in temperature. So, you will see that for Southern California, it has shifted by one year whenever they become deficit.

This next slide shows the results of SAM

No. 5 with the assumed 15 percent planning margin, and, again, Southern California/Mexico 2008 is when it goes deficit.

Then this compares Scenario 5 and 6 where we throw in the uncommitted generation which I don't think we show how much that is, but in the report it does show the generation that is added because of including that.

In this case, it goes the other way where it goes from 2008 for Southern California to 2009, about 46 isn't hardly enough to worry about, so it goes two years.

Then this compares Scenario 1 and Scenario 5. The conclusions that John published in his report where there is a capacity surplus in the Northwest. There is load growth obviously in the Southwest outpaces the known development of known new generation resources.

One thing that is discussed heavily in the report is that there are transmission constraints that are produced as this capacity surplus in the Northwest can no longer get to the South. There is a cut-plane along the Northwest and north of Idaho. We call that the North-South Split, and so all the paths between the North and

South are constrained at maximum levels.

Also based on all the scenarios, the assumed reserve margins for the summer are met until the year 2008. Then again, for winter, we have the same kind of results.

Then going forward to some more of the results just for California, this shows the transfer capabilities that were used and these values are derated from the OTC ratings based on limits that may originally be expected to apply under simultaneous high seasonal loading conditions.

What that means is that we formed a task force, and they looked at the flows that they see during the high seasonal summer peaks and came up with these ratings.

In 2007, the Palo Verde to Southern California limits are projected to be increased by a 30 percent due to the addition of upgrades such as capacitors and such. Then the 2009, the Palo Verde and Southern California Limits are also increased by the addition of the Devers 2 line. Those were both accounted for in the assessment.

This gives kind of a picture of the California results. The first line is the firm demand, the second line is non-firm demand, so we take those, then we assume a reserve margin, add them together to get a load requirement, and you will see Northern and Southern California there and then we throw in the generation resources, and this is Scenario 5 without the uncommitted additions, so those are zero. Then we have outages and derates, which are described in the report.

Some of these are hydro derates, and there might be a few MWs of scheduled maintenance, but not very much. Then the next line we have net imports, so that is imports minus exports of assigned as positive for imports.

We add those together to get the available resources, and then the power supply margin is simply the available resources minus the load requirement.

One thing that I didn't mention earlier. On the bottom line there, we show in 2005 and 2006 and 2007, we show a positive power supply margin for Southern California and Mexico. This represents resources in Mexico that are higher than their load, but cannot be exported based on our assumption on the import capability. Southern

California by itself would just be zero for those three years.

This compares the SAM net imports to the import capability for Northern California. You will see what this really means that during the early years, (indiscernible) was imported in Northern California wasn't needed in Northern California so it was exported out of that region. As the load increased in Northern California, more of that was imported stays in Northern California.

The reason it didn't get the maximum at the end there is that between -- if you remember the picture of the zones, Northern California is made up of Central California, Northern California, SMUD in San Francisco. Between Central California and Northern California on Path 15, that has a limit, so there's an internal limit to this sub-region that prevents it from going to the maximum there.

Southern California, likewise, this is net imports versus the import capability. You will see that it increases in 2007, it increases in 2009 because of the Palo Verde paths. You will see that in 2006, the net imports go down because of the retirement of the Mojave and then back up again in the next year because of new generation that is being built throughout the Southwest. It goes down and stabilizes because of the joint plans that we have in the model.

This is a different view of the results. Northern California because it is through-cut from the Northwest to the Southwest going down the (indiscernible) line is at zero until such time that the North/South split occurs in 2010 it looks like.

In Southern California, again, the positive numbers are the Mexico plants that are stranded. Then it goes down. In both of these, pretty much the slope of the lines is caused by what we have been reported, the load growth that has been reported, so they are fairly straight because we don't know about new generation out there, then the generation levels off and then all of that can affect the model then. At that point is the load growths. That is the end.

PRESIDING MEMBER GEESMAN: Thank you very much, Mr. Holland, and thank you for being here today. Are there questions from the audience for Mr. Holland? Steven.

MR. KELLY: Thank you, Steven Kelly with

IEP again. One quick question. The 1 and 2 Scenario I understand. The other scenario is a +5 degrees temperature reading. Is that equivalent to a 1 and 10 or a 1 in -- do you know?

MR. HOLLAND: No. I mean I think that in the report that was discussed previously pointed out that some points that we are not in agreement with the CEC or the CAL ISO's assessments. Part of that is because of the 1 and 10 versus what we just call a 5 degree. The other reason is the assumptions on imports.

The model, of course, it is going to let the energy flow wherever it is needed.

MR. KELLY: Does the Energy Commission staff roughly what that translates into, a five percent increase in temperature?

PRESIDING MEMBER GEESMAN: It wasn't a five percent increase, it was a 5 degree --

MR. KELLY: Excuse me, 5 degree temperature increase. Is that roughly a 1 and 10 because that is the way we usually frame it here, and I was just kind of trying to --

MR. JASKE: The main difference is not so much in the translation of the degrees into a load impacts of 1 and 10. That is not too far off in the materials from the March 21 workshop on 2005's supply and demand balance I think sort of show what our analysis of 1 and 10 means.

I think the results that Stan is talking about has more to do with the number of entities that actually reported this temperature sensitivity factor, and, therefore, their ability to bump up all load by 5 degrees. They only got about I think half the utilities to respond to their request for this new piece of information that hasn't historically been asked for. So, they are sort of still in the transition stage of being able to implement that enhanced capability.

MR. KELLY: In California, Mike, if the degrees were to increase five percent over historical average, would that be roughly for California a 1 in 10 your extreme scenario?

MR. JASKE: You are in the right ballpark. You might not be in the left field/right field, but you are in the right ballpark.

MR. KELLY: All right, thank you.

PRESIDING MEMBER GEESMAN: Other questions for Mr. Holland?

MS. DOWNEY: Carrie Downey with Horton,

Knox, Carter & Foote for the Imperial Irrigation District. On the slide that you had put the verbiage at the bottom that suggested that the power supply margin from Southern California/Mexico 2005/2007 represented the stranded surplus of CFE. When you show the switch from 2007 to 2008, all of the sudden we go from surplus to a negative 873. I'm trying to figure out are you showing that it is no longer stranded, that it is somehow now getting into California at that point? Is it because of transmission which I know the report will come in two days, or is it additional so that actually if you could never get that 225 anyway, you would actually have a deficit now of over 1,000?

MR. HOLLAND: No, that's the load growth in Mexico.

MS. DOWNEY: Then what is stranded now will be staying in Mexico?

MR. HOLLAND: Yes. That is an issue that we hope to address before next year's assessment where we can better model that path between Mexico and California because right now we have the generation that was built in Mexico is owned by California. We actually have that up in

California in this model, and it is easier for the model to work if you put it where it really is.

MS. DOWNEY: Thank you.

MR. BROWN: Good morning, Andy Brown with Ellison, Schneider & Harris. Thank you, you just answered one of my questions with respect to the stranded generation down in Mexico.

I'm looking forward to looking at the details in the report, but I am wondering is there a breakout in the details of the report that would identify what is stranded down there in terms of generation to Mexico?

MR. HOLLAND: You mean an amount, like MW amount?

MR. BROWN: Yeah, or highlighting that issue more specifically.

MR. HOLLAND: I don't think necessarily. The results just show that is there and when we first saw that, we looked to see what was causing that because we knew they were importing into California, and we saw that it was generation in Mexico.

MR. BROWN: My other question relates to when you were going through the colored tables, and there was one I think it was for Southern

California where it flipped to -46, and we were looking at it going red at -46, but you essentially were saying that wasn't too material. You sort of treat it like zero, and I am wondering where is the -- is the rounding a plus and minus thing? What kind of number would you essentially push things to zero at?

MR. HOLLAND: We reported that they came out, but there is a lot of assumptions made, we have a lot of disclaimers in the report. I don't know what number it would be, but I think until you see between 100 and 200, that you might want to round down.

MR. BROWN: Okay, thank you.

PRESIDING MEMBER GEESMAN: Other questions for Mr. Holland? Mike.

MR. JASKE: Stan, on the two bar graphs near the end that show the net imports, particularly the Southern California one, this is a question of interpretation? The bar for 2009 I believe is the point that you indicated that the increased capacity from Deever Palo Verde 2 comes into operation. So, I think that is why the bar goes up, but the actual use, it just happens to go down, so it would seem to suggest that for at least reliability purposes, that line isn't used for that purpose. It may have other benefits, but it is not needed from a liability perspective. Is that the right interpretation of this graph?

MR. HOLLAND: It all depends on how much generation gets built in the Palo Verde area. If there is not more generation built there, then more of the generation what we needed for Arizona and New Mexico.

MR. JASKE: It sounds as though for it to provide reliability benefits to California it has to be an increase in available generation to go along with the increase transfer capability so that you actually get more imports into Southern California?

MR. HOLLAND: That is the unknown factor.

MR. JASKE: All right. Okay, thank you.

PRESIDING MEMBER GEESMAN: Okay, why don't we go to our gentleman from BPA who I think is going to address us by telephone. Good morning.

MR. MAINZER: Good morning, this is Elliot Mainzer, I am the Acting Vice President of Bulk Marketing and Transmission Services. I am also joined here this morning with Steve Oliver, who is our VP of Generation Supply, and Karen Connelly, who is our Manager of Regional Coordination.

I appreciate the opportunity to comment this morning on the Western Electricity Supply Outlook Report. I wish we could be there in person to join you, but I had a little bit of short lead time on this. We did have an opportunity, however, to review Chapter 3 of the Supply Outlook Report. We had it reviewed internally by BPA Operations and Marketing staff and by several technical staff at the Power Council.

Overall, we felt that the findings of the report were consistent with our general view of load resource balance and new resource development in the region. As you know, exports to California from our part of the world are largely a function of the amount of hydro power in the Columbia River Basin and other Northwest (indiscernible).

If you look back to 1990, the correlation between your exports to California and flows on the Columbia River at the Dows, Oregon is about 80 percent. In the absence of sustained drought or the loss of substantial generating capacity, we believe that surplus Northwest power should continue to be available for export to California over the interties at levels reasonable consistent with historical practice.

I did assemble a number of minor edits and potential suggested clarifications on a report that I will forward to Commission staff is that is valuable. I also wanted to mention one quick technical point. With respect to the Scenario Analysis 1 in Chapter 3 concerning the ability of the Northwest to meet various load levels in the reserve margin, there were a few technical questions on the part of counsel staff about the (indiscernible) of these numbers that are best resolved off line I imagine. I don't think they were concerns with the essential findings, just several questions on methodology and comparability.

Since the counsel staff and others typically address this question using loss of load probability models with explicit assumptions about hydro system capability, so it might be useful following today's session to arrange for maybe a little bit of follow up with a few of the technical staff who worked on the report and a couple of the people at the Power Council.

What I wanted to do was provide a bit more context and color regarding some of the key Northwest policy issues that will shape resource development and potentially exports to California over the next decade. The report did allude to a few of these, and I wanted to provide a little more context.

The first issue is known as the regional dialogue on the future role of BPA in regional power supply. BPA is currently engaged with the region in a substantial debate about the future role of Bonneville in meeting the incremental load growth of our customers in the post 2011 period when our current power contracts expire.

We are actually proposing a tiered rates construct in which BPA will limit its sales of power at its lowest cost base rates to the firm capability of the federal hydro system, which is currently estimated at around 7,300 MWs.

Under this construct, customers will have the option of meeting their incremental load growth through other suppliers by placing their load on BPA, but paying a market-based rate for their incremental demand. This tiered rates construct is designed to clarify responsibility for meeting load growth and to send marginal price signals for the next round of resource development in the Northwest. BPA expects to come out with a final proposal for this new approach in early 2006.

One point of clarification that I wanted to offer that seemed to be a bit unclear in the report concerned the role of Bonneville with respect to resource development. Since 1980, BPA has been with the signing of the Northwest Power Act, BPA has not been authorized to build new generating facilities. We are only allowed to purchase the output of new generation to meet customer load.

We anticipate that a substantial number of our full requirement customers will purchase their incremental or Tier 2 power from us in the future so we will likely continue to be in the power purchase business for the foreseeable future.

Since we will be limiting our sales of cost-base power to the firm capability of the system, we will continue to have surplus power to export to other regional markets under most water conditions.

I did want to make it just clear that Bonneville probably will not be getting completely out of the power purchase environment, particularly if our smaller full requirements customers continue to stay with us in the future.

I next wanted to talk about the SLICE System products. Beginning in 2002, Bonneville began marketing 22.8 percent of the federal hydro system output under a SLICE system product.

Under SLICE, Bonneville's SLICE customers purchased a fixed percentage of federal hydro system energy and capacity and have various storage rights and flexibility for the attempt to mirror the rights available to BPA.

Bonneville still has overall operational control of the system and SLICE must not interfere with meeting any of the critical non-power constraints on the system. As a result of offering the SLICE product, 22 percent of the system's surplus energy is now marketed by SLICE customers. Examples include Seattle City Light, Eugene Water and Electric Board, and some of other larger somewhat more sophisticated power marketing customers.

The SLICE product has been the subject of some controversy here in the Northwest, and we are currently evaluating the product and its future as a part of our broader regional dialogue discussion. SLICE is important to California because it does have a major impact on how the region markets surplus power, and depending on how we move forward with SLICE, the number of counterparties that trades with California could increase or decrease, potentially raising credit issues and creating a wider number of decision makers affecting the level of exports to California.

Generally, however, SLICE customers have and I would say are expected to market their power economically so if price signals are there for exports to California, surplus power will likely find its way there.

One other point I wanted to make, however, is that over time, SLICE customers may choose to use increasing amounts of their surplus SLICE power to meet their incremental load growth which could erode the amount of surplus available for exports to California. This is something that probably merits a little bit of additional research.

The next one I want to talk about is the direct service industry. As many of you are probably aware, the power crisis was quite devastating to the Northwest aluminum industry, which has been one of the sort of economic mainstays of the Northwest for about 50 years.

Smelter loads are actually down from 3,000 MWs since 2000 to only 300 MWs at present. EPA recently announced a decision to offer 577 MWs of financial benefits to the DSI for the 2007 to 2011 period in an attempt to help conserve jobs in the region, but alumina and aluminum prices may conspire to further reduce DSI operations.

The level of DSI operations has obvious implications for the amount of surplus power available to market to California.

I also wanted to mention renewables and renewable facilitation. Bonneville has had considerable interest from a number of wind developers up here in the Northwest hoping to market their power to California to help meet demand spurred by the State's portfolio standard.

At BPA, we are prepared to offer wind integration services to these developers using the flexibility of the hydro system to help them manage the intermittent nature of their power, but limited firm transmission rights across the interties has prevented any deals from going forward so far.

There is obviously a substantial wind resource here in the Northwest that represents a substantial potential source of supply to California, but I do imagine we will need to build additional transmission to accommodate such transfers or get a lot more comfortable about the use of non-firm transmission to make that happen.

The second to the last point I wanted to talk about is resource adequacy. Like you in California, BPA is also grappling with this issue, and we are working with the WECC, NERC, the Power Council, our public power customers, and the regions investor-owned utilities to actually define a resource adequacy metric and the standard for the Northwest. This is obviously a very important region-wide issue.

There are many Northwest staff working diligently with other regional entities to determine the extent to which inter regional transfers, particularly imports to the Northwest from California can actually be depended on to meet winter peaking load for the Northwest.

It is likely that BPA will continue to plan to a critical firm standard if we adopt a resource adequacy standard which will result in on-going presence of considerable surplus power under most water conditions for export to California. Resource adequacy, of course, is a topic which is getting more and more important here in the Northwest.

Finally, all of this activity, of course, is juxtaposed against wider debate over the future of grid west, sort of the RTOish like conversation that is happening here in the Northwest.

Like many parts of the country, the Northwest is very much in search of a better approach of transition planning, congestion management, and reliability. We are expecting some major developments on this front in October, with a pending decision on whether to move forward with the next stage of grid west or to pursue other options such as the transmission improvements group, or possibly bi-lateral REGIS (indiscernible) arrangements to help mitigate and manage congestion issues.

From the perspective of California, of course, a more efficient Northwest grid will help maintain if not increase the amount of power available for export to California. Those are several of the big policy issues.

I now just want to pass it over to Steve Oliver who is going to talk a little bit about some of the recent biological opinion issues that have been turning here in the Northwest.

MR. OLIVER: Thanks, Elliot. I don't have a lot to add. I would just say that in 2004, Northwest federal agencies produced a plan to operate the river and of course with the Endangered Species Act for purposes of mitigating impacts and dangers to salmon species.

That plan was challenged by various parties as insufficient to meet a new jeopardy operation for the endangered species with regard to both flow and bypass. The court subsequently ordered increased spill on the Lower Snake Project (indiscernible) Dam, and beginning June 20, for the Lower Snakes and July 1 McNarry through

August, the spill requirement basically derates Northwest hydro system by 1,500 MWs of capacity over that period and about 450 average MWs of energy.

Basically the court-ordered spill is being appealed, and it is not clear whether this will becoming norm for future operations or not. This is something that needs (indiscernible).

That is really all I have on one of the more recent events happening on the system.

PRESIDING MEMBER GEESMAN: Steve, is the order itself just for the one year?

MR. OLIVER: Yes.

PRESIDING MEMBER GEESMAN: Okay.

MR. MAINZER: There is definitely a big variable here. That is all we have to offer in terms of prepared remarks.

PRESIDING MEMBER GEESMAN: I want to thank you all very much for joining us today. Are there any questions from the audience for Mr. Mainzer or Mr. Oliver?

MR. ALVARADO: This is Al Alvarado with Energy Commission staff. I just wanted to also thank you Steve and Elliot for participating in this hearing, and we will follow up with a discussion with you later on to discuss some of the technical issues and any corrections that are needed to our report. Thank you.

MR. MAINZER: Thank you.

MR. OLIVER: Okay, I'll look forward to talking to you.

MR. ALVARADO: Sure thing.

PRESIDING MEMBER GEESMAN: Is there any additional comment that any members of the audience would care to share with us?

MR. KAKUK: Good morning, my name is Janos Kakuk, and I am in the Resource Planning Group at Southern California Edison. I have some general comments on the report.

First, I would compliment the staff on the preparation of the report. This report we believe serves an important function by providing an integrated statewide outlook of the expected demand supply forecast over the next five years. We also believe that the CEC provides unique at looking statewide supply generally.

This report also might have the developers to see where and when new resources will be needed.

There is one area where we have some

slight disagreement or we missed some further analysis. The reports states that beyond 2006, if aging power plants want to be replaced, the required 7 percent operating reserve matching will not be met in very hot weather.

The first assessment we find only two scenarios, the base case with no retirements and the high retirement case. Another scenario which would lie between the two cases might be maybe more appropriate, we believe so. The reason is because the scenario, the base case scenario showed no need for new resources through 2010. The high retirement scenario showed needs as soon as 2006.

We believe that both cases ignore some important assumptions. For example, the case, the high retirement case did not take into consideration the availability of existing a new demand response programs in the forecast of the expected supply of that (indiscernible).

Another point is that the report does not take into consideration nor even mentions the California ISO approved serious capacitor upgrade to DPV 1. There is a high likelihood that DPV 2 will be completed in later of the year of the study.

PRESIDING MEMBER GEESMAN: Do you have a specific year in mind for DPV 2?

MR. KAKUK: Depending on the application as soon as 2009.

The highest retirements scenario seems to be conservative considering also the most recent California ISO local area reliability assessment, which shows need for over 8,500 MW of local generation. In order to meet this local area reliability requirements, some of the power plants indicated that is high probability for their retirement need to keep in the line.

Finally --

PRESIDING MEMBER GEESMAN: Do you envision, and I'm not familiar with that ISO report, but do you envision that prompting greater reliance on RMR contracts?

MR. KAKUK: For some other structure needed, but these power plants need to be kept on line.

Finally, to meet the RPS standard, we need also procure more and build renewable resource plans. So, generally, we agree as indicated in the WECC analysis that some shortages might occur as soon as 2008, but we just simply don't feel the need to over estimate their potential shortages.

However, even we discover it, SC agrees that in the remainder of the (indiscernible), they will be increasing resource need, and in the regulatory and the market uncertainties we are facing, it is difficult to see how this new generation will be built. That is why we took our initiative and launched our long-term RFO. We believe that other load serving entities should follow our example and to also meet their portion.

Thank you very much.

PRESIDING MEMBER GEESMAN: Thank you. Other comments from members of the audience?

MR. BROWN: Andy Brown, Ellison, Schneider, and Harris. I was asked to relay some brief comments by Duke Energy North America.

Duke would like to point out on page 20, a paragraph there that they really applaud the staff for including in the report, and I will read it because it is pretty brief. "Resource adequacy in California through 2010 will be influenced to a large extent by the continued operation of power plants at risk for retiring due to lack of financial incentives. If these plants are retired and their capacity is not replaced by alternative resources, California will not be able to maintain minimum required operating reserve margins beyond 2006 during period of very hot temperatures, and the California ISO Southern Region will fall below minimum required operating reserves in 2006 during normal temperature conditions."

This is an issue, particularly with respect to the existing resources, like some of Duke's assets, that the company has been trying to highlight for a number of years. They've been promoting what they are calling an interim or bridging contract to insure that existing capacity remains available to the system while either plant modernizations or other capacity additions are to occur.

We really wanted to applaud the Commission, the staff, for highlighting this argument. We think it is very critical in these coming years, and the company will be making some brief reply comments to that effect. Thank you.

PRESIDING MEMBER GEESMAN: Thank you. Other comments?

MS. DOWNEY: Carrie Downey again for the

Imperial Irrigation District. We just wanted to add our accolades on the great work done by Jim Woodward and the staff in compiling the data for IID, since obviously submitting information that we consider either confidential or not yet approved was tricky. I just want to commend Jim and the entire staff in the department for making it easy, and I think getting information that you will be finding helpful. Thank you.

PRESIDING MEMBER GEESMAN: Other comments?

(No response.)

PRESIDING MEMBER GEESMAN: Okay, I want to thank you all very much. We will be adjourned.

(Whereupon, at 10:52 a.m., the Committee meeting was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Meeting; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said meeting, nor in any way interested in outcome of said meeting.

IN WITNESS WHEREOF, I have hereunto set my hand this 7th day of August, 2005.